Electric Transmission Constraint Study:
Data Sources and Calculation Methods
Federal Energy Regulatory Commission
Office of Markets, Tariffs, and Rates
December 2001

I. Overview

This document supplements a presentation to the Federal Energy Regulatory Commission on December 19, 2001. It provides more detailed information on the data and calculations used. Sixteen severe constraints[1] in the United States were selected and the cost of congestion on each was estimated. In the accompanying presentation the constraints are grouped as follows:

Western Interconnection, which includes the electrically interconnected grid west of the Rocky Mountains and also includes the California Independent System Operator (CA ISO);

Rest of Eastern Interconnection, which includes the electrically interconnected grid of the eastern U.S. (outside of the Northeastern U.S. region, which is also a part of the Eastern Interconnection);

Northeastern U.S., which includes the Independent System Operator of New England (ISO-NE), the New York Independent System Operator (NYISO), and PJM Interconnection, LLP (PJM).

The general method used to compute the cost of transmission congestion is discussed in Section II. In Section III, the information sources, the selection of constrained interfaces, and calculation of congestion costs are described for each region. Within the limits of available information, the general framework in Section II was applied to the calculation of congestion costs in each region.

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[1] The terms "constraint", "interface", "flowgate", and "path" are used interchangeably here. All refer to sets of transmission lines and related equipment that can become loaded to their physical limits, that is, "congested" or "constrained."

II. General Approach

The sixteen selected interfaces each have some of the characteristics of congestion: they operate near their physical limits frequently or for extended periods, generate significant price differences, are subject to Transmission Loading Relief events, or require the operation of phase shifters[2] to moderate congestion. More specific information is given in the regional descriptions below.

Transmission congestion raises costs to the consumer by limiting access to the least expensive power, as the example below will show. The increased cost caused by congestion has two parts: the *congestion rent* (the price difference between the ends of the constraint multiplied by the flow across the constraint) and the *replacement cost* (the cost of energy to replace energy that could not flow across the constraint). The following example shows how to calculate the cost of congestion by comparing two cases: one where there is no congestion in the system, and one where congestion causes increased costs to customers. For the case with congestion, the example shows how the congestion rent and the replacement cost are calculated.

Case 1: A Simple System with No Congestion

Figure 1 shows a system with two buses, two transmission lines, three generators, and a load at each bus. At Bus A, power from Generator #1 flows into the bus, and power flows out to the load and to transmission lines #1 and #2. At Bus B, power from Generator #2 and from both transmission lines flows into the bus, and power flows out to the load.

In this case there is no congestion, and Generators #1 and #2 (the two cheapest generators) are providing all of the power. Each transmission line is sending 75 MW from Bus A to Bus B, and there is no congestion since neither line is at its limit. The load at Bus B is supplied both by its local generator, Generator #2, and by transmission from Generator #1 at Bus A. The marginal price (the price to supply the next increment of load) is $20/MWh, because that is the cost to increase the output from Generator #1 (Generator #2 is cheaper at $18/MWh, but is already at full output). The outputs and costs are shown in Table 1.

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[2] A phase shifter is an adjustable transformer that alters the electrical characteristics of transmission systems so as to direct power flow in a desired direction.
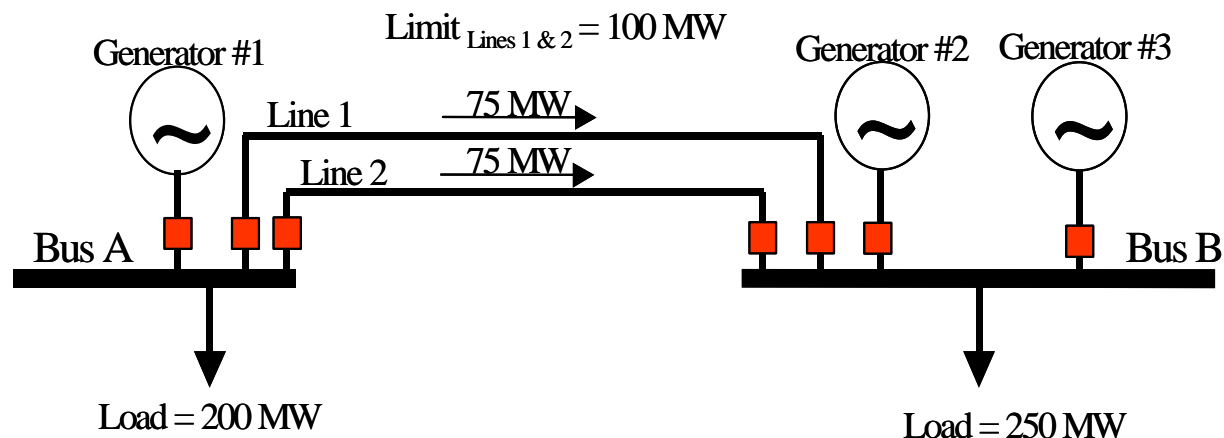
Figure 1: No Congestion

Figure 1: No Congestion — Generator #1 at Bus A connected via Line 1 (75 MW) and Line 2 (75 MW), Limit $_{Lines\ 1\ \&\ 2}$ = 100 MW, to Bus B with Generator #2 and Generator #3. Load = 200 MW at Bus A, Load = 250 MW at Bus B.

Table 1	Gen #1 max = 500 MW @ $20/MWh	Gen # 2 max = 100 MW @ $18/MWh	Gen#3 max = 75 MW @ $30/MWh	Customer Load at Bus	Customer Price at Bus	Total Cost to Customer
Bus A	350 MW			200 MW	$20/MWh	$4,000/h
Bus B		100 MW	0	250 MW	$20/MWh	$5,000/h
Total	350 MW	100 MW	0	450 MW		$9,000/h

Case 2: The Same System with Congestion

In Case 2, shown in Figure 2, the load is the same as in Case 1, but congestion occurs because transmission line #2 is disconnected. Transmission line #1 is now operating at its maximum capacity of 100 MW. The combined transmission flow, which was 150 MW in Case 1, is now limited to 100 MW. In this case, the load at Bus B cannot be met with transmitted power plus output from Generator #2 , as it was in Case 1. Instead, Generator #3 must generate 50 MW, at a cost of $30/MWh (and Generator #1 must decrease output by 50 MW). Now there are two marginal prices: $20 at Bus A (because the next increment can come from Generator #1) and $30 at Bus B (because the next increment must come from Generator #3, instead of from Generator #1.) The outputs and costs are shown in Table 2.
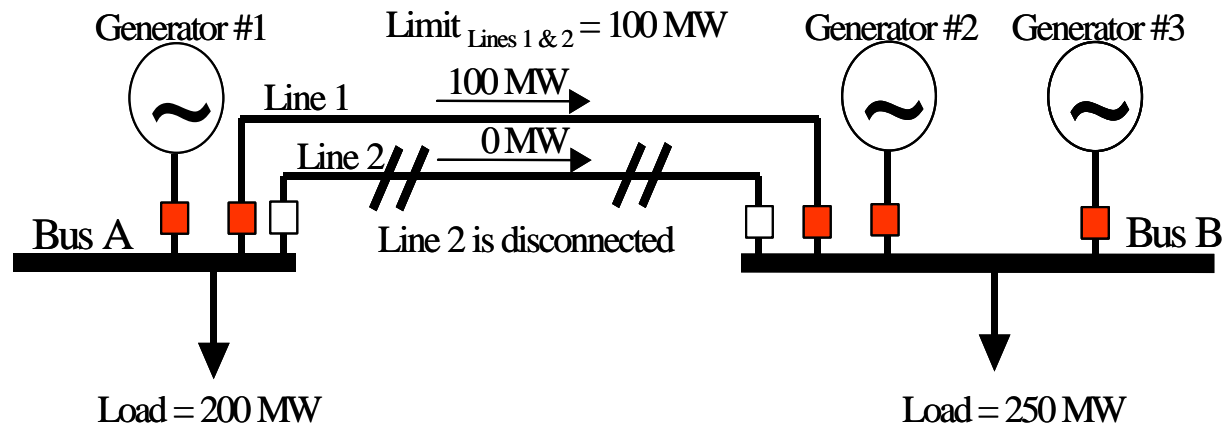
Figure 2: Congestion

Generator #1   Limit $_{Lines\ 1\ \&\ 2}$ = 100 MW   Generator #2   Generator #3

Line 1   100 MW →

Line 2   0 MW →

Bus A   Line 2 is disconnected   Bus B

Load = 200 MW   Load = 250 MW

Table 2	Gen #1 max = 500 MW @ $20/MWh	Gen #2 max = 100 MW @ $18/MWh	Gen #3 max = 75 MW @ $30/MWh	Customer Load at bus	Customer Price at bus	Total Cost to Customer
Bus A	300 MW			200 MW	$20/MWh	$4,000/h
Bus B		100 MW	50 MW	250 MW	$30/MWh	$7,500/h
Total	300 MW	100 MW	50 MW	450 MW		$11,500/h

We can calculate the congestion costs for Case 2 as follows:

Congestion rent = (sink price - source price) x (flow across interface)
= ($30/MWh -$20/MWh) x (100 MW)
= $1,000 per hour

Replacement cost = (sink price - source price) x (load - flow across interface)
= ($30/MWh - $20/MWh) x (250 MW - 100 MW)
= $1,500 per hour

Total Cost to Customer of Congestion = $1,000 (congestion rent) + $1,500 (replacement cost)
= $2,500 per hour

III. Description of Regional Data and Methods

A. Western Interconnection

1. Information Sources

>   WSCC[3] Path Rating Catalog - a WSCC-maintained compilation of transfer limits, operating nomograms, descriptions of transmission facilities, and other information for 68 paths in the Western interconnection.
>
>   EHV (Extra High Voltage) data pool - WSCC collects actual hourly loading for 34 paths.
>
>   Unscheduled Flow Mitigation Procedure Log - logs of phase shifter operations and curtailments of transactions to relieve congestion on the nine paths presently qualified for the unscheduled flow mitigation plan.
>
>   CA ISO Reports - Monthly market analysis reports for 2000 and upgrade analysis reports are published by CA ISO on its web site.

2. Selection of Constrained Interfaces

We reviewed EHV data pool for the entire year 2000 and January - July of 2001. A list showing loading levels higher than 90% of the path's capability was prepared for each year. For example, Path 19 (Bridger West - ID/WY) was loaded more than 90% of its rated capacity for approximately 3,000 hours for both year 2000 and 2001. We reviewed the EHV logs for 1999 and 2000 and ranked the paths in order of their severity. From the CA ISO Reports, we ranked various paths on the basis of percent of time they were congested.

3. Calculation of Congestion Costs

The calculation of congestion costs for the WSCC was similar to the calculation of congestion costs for the Eastern Interconnection (outside the ISOs in the Northeast), except that it included only congestion rent, and not the cost of replacement energy. Congestion rent was calculated as the estimated value of power per MW of the congested path times the flow on the path. Replacement energy was not included because the available WSCC information did not include the type of information provided by TLRs in the east that was used to identify the specific curtailed transactions.

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[3] WSCC is the Western Security Coordinating Council, the regional reliability council of the North American Electric Reliability Council for the western U.S.

To calculate the congestion rent, a value was assigned based on the flow across the specific congested path (Paths 15, 26, 65, 66, 19, or 22) and the price difference between the source and the sink for the path. The calculation was performed for each hour. A path was considered congested if loaded above 90% in a particular hour (based on the percentage of the limit in the WSSC data) for paths outside the CA ISO, or above 70% for paths inside the CA ISO. The CA ISO paths were assigned a lower level, based on a comparison of the hours congested in 2000 (as reported by the CA ISO) and the percentage loading on the California paths (Paths 15, 65 and 66[4].) CA ISO-reported hours corresponded most closely to path loading of 70%.

The source and sink pricing points for each of the selected paths, taken from Bloomberg pricing data, are shown in Table 1. The price separation is the difference between the source and sink prices shown in Table 1, based on the on- or off-peak period prices reported daily by Bloomberg. The total congestion cost was then calculated for path *i* as:

$$CC_i = \sum_j F_{ij} * (Psk_{ij} - Psr_{ij})$$

Where:

CC_i = total congestion cost for path i
F_{ij} = flow on Path i in hour j, where j ranges over all congested hours
Psk_{ij} = Bloomberg price for the Path i sink in hour j (on- or off-peak)
Psr_{ij} = Bloomberg price for the Path i source in hour j (on- or off-peak)

Table 1. Sources and Sinks for Bloomberg Pricing Points

Path	Source Point	Sink Point
Path 15	NP15	SP15
Path 26	NP15	SP15
Path 65	NP15	Mid-Columbia
Path 66	SP15	Mid-Columbia
Path 19	Ault, Colorado	Average of NP15, SP15 and Mid-Columbia
Path 22	Four Corners	SP15

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[4] Path 26 data in the EHV data were incomplete. Costs for Path 26 were taken directly from the congestion cost data in the CAISO website, CAISO.COM.

B. Eastern Interconnection

1. Information Sources

NERC Transmission Loading Relief (TLR) Database – A NERC maintained database of information describing TLR events. The database provides the Facility ID (Flowgate ID), Facility Name (Flowgate Name), TLR level, constrained flow direction, Initiating Party (Control Area), Responsible Party (Security Coordinator) and start date and time.

The NERC Interchange Distribution Calculator (IDC) – In addition to the information provide by the NERC TLR database, IDC data provided the Electronic Tag name, source control area, sink control area, MW schedule, MW curtailed, MW relief, transaction priority, and TLR status for each TLR event.

NERC System Flows – A NERC sponsored, current-time, system flows database. System flows are provided by third parties for 100 selected NERC flowgates. NERC does not provide system flows for all NERC flowgates.

Megawatt Daily – An electric utility trade publication. The source and sink daily prices were obtained from the *Megawatt Daily* hub prices for peak periods (sixteen hour products).

2. Selection of Constrained Flowgates

The Eastern Interconnection flowgates in the Electric Transmission Constraint Study were selected based on the number of TLRs level 3 and above that were implemented on the subject flowgates during the summer months of June, July and August of 2000 and 2001.

Due to the abnormal weather pattern that occurred in Summer 2000, where the northern U.S. was cooler than the southern U.S., the "most active" flowgates in Summer 2000 varied somewhat from Summer 2001, when the weather pattern was closer to normal for that time of year. For example, the Southwest MI area constraint was selected because of the constrained south to north flows which restricted power into Michigan during the implementation of higher level TLRs. This was generally not the case in Summer 2000 when the weather pattern resulted in flows from north to south.

3. Calculation of Congestion Costs

The total congestion cost associated with each flowgate was estimated to be the sum of the congestion rent (the locational marginal price difference between the sink and

source control areas multiplied by the flow limit) plus the replacement energy cost (the locational marginal price difference between the sink and source control areas multiplied by the load minus the flow limit). Due to the limitations of the data, the estimated total congestion cost in the Midwest should be considered the "lower bound" congestion cost. The amount of load curtailed for each flowgate is known, but we did not have the total load for each flowgate nor the flow limit for every flowgate, since NERC only provides system flows for a selected 100 flowgates. Refer to the example in Section II, General Approach, for a sample calculation.

C. Northeastern U.S.

1. ISO New England

a. Information Sources

> RTEP01 - Regional Transmission Expansion Plan 2001, an assessment of New England's transmission system conducted by ISO-NE and issued October 2001. Identifies geographic subareas with marginal or deficient supplies relative to generation and interconnection (including the Boston and Southwest Connecticut areas selected for this study).

> ISO-NE Monthly Market Reports - contains data on "transmission uplift" (socialized congestion costs) by geographic subareas.

> ISO-NE web site - contains hourly price data and other material.

> Discussions with ISO-NE staff - to confirm configuration and other characteristics of the selected interfaces.

b. Selection of Constrained Interfaces

The Southwest Connecticut and Northeast Massachusetts/Boston interfaces were selected for examination in this study. RTEP01 identifies the Southwest Connecticut subarea as "deficient" in reliable and economic supply, and the Boston subarea as "marginal". It predicts significant congestion expenses for both interfaces through 2006. ISO-NE staff confirmed that the Southwest Connecticut interface is the most congested in the ISO-NE system.

c. Calculation of Congestion Costs

Congestion costs of the two interfaces in the ISO-NE area (Boston and Southwest Connecticut) are based on ISO-NE payments to "out-of-merit" generators; that is,

generators that would not be selected to run except for transmission congestion. These payments (called "mitigated uplift" after bid adjustments by ISO-NE) are allocated to various geographic subareas by ISO-NE and are reported in their monthly reports. The portions of uplift allocated to the Boston and Southwest Connecticut subareas are the congestion costs attributed to the corresponding interfaces in this study.

2. New York ISO

a. Information Sources

NYISO 1999 Transmission Performance Report - contains data on power flows and operating limits of NYISO transmission interfaces.

NYISO Transmission Use Statistics for January-December 1999

Review of the Reliability of the New York State Bulk Power Transmission System in the Year 2006 - assesses several performance criteria for the NYISO transmission system.

Discussions with NYISO Staff - to confirm severity and configuration of selected interfaces.

b. Selection of Constrained Interfaces

The Central East interface was selected for review because it is clearly the most congested interface in the NYISO system (based on frequency of loading near its limits and confirmed by conversations with NYISO staff). It is also a large interface (consisting of two 345 kilovolt (kV), one 230 kV, and three 115 kV lines) in a location central to the NYISO system.

c. Calculation of Congestion Costs

The New York Independent System Operator (NYISO) administers a two-settlement market with Locational-Based Marginal Pricing. The territory is divided into eleven internal zones; each zone has an hourly price in the day-ahead market and in the real-time market. Each price has three components: an energy component (which is the same for each zone), a loss component, and a congestion component. NYISO publishes the prices and their components, as well as the hourly loads for each zone.

The congestion components of the NYISO prices were used to estimate the total monthly costs of congestion in the NYISO system, and to estimate the monthly costs of congestion at the Central East Interface.

NYISO Monthly Congestion Costs

For the total monthly costs of congestion, the day ahead and real-time congestion components of each zonal price were multiplied by the actual zonal loads during each corresponding hour in a month. The resulting products were weighted with the monthly market share of the real-time market (published by NYISO in its Monthly Reports):

$$C_{nyiso} = (1 - M_{rt}) \sum P_{da}L + M_{rt} \sum P_{rt}L$$

where:

C_{nyiso} = monthly congestion cost in NYISO
M_{rt} = monthly market share of real-time market
P_{da} = congestion component of hourly day ahead price in zone x
P_{rt} = congestion component of hourly real-time price in zone x
L = actual hourly load in zone x

Central East Interface Monthly Congestion Costs

An hourly congestion cost was estimated for each of the two markets (day ahead and real-time). The Central East Interface terminates in the Mohawk Valley zone (to the west) and in the Capital zone (to the east). In the NYISO pricing system, the congestion component of a zonal price is an estimate[5] of the marginal cost of congestion in that zone relative to the reference bus, which is the Marcy bus on the west side of the Central East Interface in the Mohawk Valley zone. Therefore the difference in the congestion components of the Mohawk Valley and Capital zones is an estimate of the marginal Central East congestion cost. This difference was multiplied by the sum of the loads of all zones east of the Central East Interface (Capital, Hudson Valley, Millwood, Dunwoodie, New York City, and Long Island):

Hourly Central East Congestion Cost =

Day ahead: $(P_{da\text{-}Capital} - P_{da\text{-}Mohawk}) \sum\limits_{i=Capital}^{LongIsland} L_i$

Real-time: $(P_{rt\text{-}Capital} - P_{rt\text{-}Mohawk}) \sum\limits_{i=Capital}^{LongIsland} L_i$

where:

$P_{da\text{-}Capital}$ = congestion component of hourly day ahead price in Capital zone

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[5] Because of metering limitations in NYISO, zonal prices are load-weighted averages of all the bus prices in a zone, and so are not exact nodal prices.

$P_{da\text{-}Mohawk}$ = congestion component of hourly day ahead price in Mohawk Valley zone
$P_{rt\text{-}Capital}$ = congestion component of hourly real-time price in Capital zone
$P_{rt\text{-}Mohawk}$ = congestion component of hourly real-time price in Mohawk Valley zone
L_i = actual hourly load in zone i

To determine the monthly totals, the hourly congestion cost estimates were summed and weighted by market share:

Monthly Central East Congestion Cost =

$$(1 - M_{rt}) \sum \text{ hourly Day Ahead Central East congestion costs of month} +$$

$$M_{rt} \sum \text{ hourly Real-Time Central East congestion costs of month}$$

where:
M_{rt} = monthly market share of real-time market

3. PJM Interconnection, LLP

a. Information Sources Selection of Constrained Interfaces

All information on PJM congestion costs was obtained directly from the PJM web site or from the PJM market monitoring unit.

b. Selection of Constrained Interfaces

The PJM Eastern Interface (between PA and NJ) was selected as the most important constrained interface in PJM. During 2000 and 2001, congestion occurred on several PJM interfaces where power was flowing from west to east across PJM, either to meet high loads in the eastern portion of PJM, or to meet high loads to the northeast of PJM, in NYISO or ISO-NE. Congestion on the Eastern Interface occurred at a high level in both 2000 and 2001, and PJM cited the Eastern Interface as the one most frequently congested.

c. Calculation of Congestion Costs

Congestion costs were calculated by PJM in two steps, as follows:

In the first step the total cost of congestion was determined for each hour, based on the locational marginal prices (LMP) during the hour. Costs were the sum of three types

of congestion charges: implicit congestion charges, explicit congestion charges, and spot market costs. Implicit congestion charges are those paid by buyers and sellers of energy in PJM. For these charges, the amounts paid for congestion are implicit in the amounts they pay for energy received and the amounts they are paid for energy delivered. Explicit congestion charges are those paid by buyers of transmission service, who schedule energy in PJM but do not buy or sell energy with PJM. These buyers of transmission in PJM pay for transmission explicitly, based on the LMP differences between their delivery and receipt points. The congestion charges paid in the spot market are calculated as the difference between total spot market purchase payments and total spot market sales revenues.

In the second step the total cost of congestion in each hour was allocated to the constraints that were active during the hour. If only one constraint was active, all the congestion costs were assigned to that constraint. If multiple constraints were active the total congestion costs were assigned to constraints in proportion to the LMP separation across the constraint. Totals by month and constraint were then calculated from the hourly data.